# for OPERATING PERMIT 960PPB133 to be issue to:

Public Service Company - Comanche Station
Pueblo County
Source ID 1010003

Prepared August, 1998
Revised March and July 1999, December 2001, February April 2002
Revised April 12, 2002 based on comments received during Public Comment
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# I. Purpose

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. The conclusions made in this report are based on information provided in the original application submittal of February 15, 1996, additional technical information submitted on November 15, 1996, March 31, 1997, August 7 and December 4, 1998, June 23, and September 29, 1999 and December 12, 2000, comments made on the draft operating permit and technical review document submitted June 10, 1999 and February 7, 2002, comments on the draft permit received during the Public Comment period, e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements in Regulation No. 3, Part B, Construction Permits, and have been found to meet the applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence.

# **II.** Source Description

This source is classified as an electrical services facility under Standard Industrial Classification 4911. This facility consists of two (2) boilers used to produce electricity. Both units are rated at 350 MW. Each unit exhausts through a baghouse to control particulate emissions. In addition, other significant emissions sources include fugitive emissions from coal handling and storage, ash handling and disposal and vehicle traffic on paved and unpaved roads. There are also sources of particulate emissions from coal and ash handling that are considered point sources. These sources are conveying and crushing of coal and operation of the two ash silos. Finally, there are two (2) cooling water and two (2) service water towers at this site which emit particulates in "drift" and evaporate chloroform from the cooling water into the air.

This facility is located at 2005 Lime Road in Pueblo, in an area that is designated as attainment for all criteria pollutants. There are no affected states within 50 miles of this facility. The Great Sand Dunes National Wilderness Area, a federal class I designated area, is within 100 km of this facility. The Great Sand Dunes National Monument, those portions not included as National Wilderness Areas, is federal land within 100 kilometers of the facility. This area has been designated by the State to have the same sulfur dioxide increment as federal Class I designated areas.

This facility is a major stationary source for the purposes of Prevention of Significant Deterioration (PSD) requirements, however, it was constructed prior to the adoption of PSD regulations and the implementation of best available control technology (BACT). Based on the information available to the Division and supplied by the applicant, the Division believes that modifications up to this point have not triggered PSD review requirements. For purposes of future PSD review, Boral Material Technologies, Inc. operations (permitted under Colorado Construction Permit 01PB0016) shall be considered in conjunction with this facility. Note that Boral must submit an Operating Permit application for their operations within the near future and Operating Permit No. 02OPPB241 has been assigned for this facility. Although the emissions from the Boral Material Technologies operations must be considered by Public Service Company when performing PSD review, Public Service Company asserts that the operation of these units in accordance with construction permit 01PB0016 is the sole responsibility of Boral Material Technologies, Inc. Emissions at the facility are as follows:

Pollutant	Potential to Emit - 100% Coal <sup>1</sup> (tons/yr)	Actual Emissions <sup>2</sup> (tons/yr)
PM <sup>3</sup>	4,718	490.7
PM <sub>10</sub> <sup>4</sup>	3,182	153.9
SO <sub>2</sub> <sup>5</sup>	33,177	14,361
NO <sub>X</sub> <sup>6</sup>	12,705	6,978
VOC	85	82.6
CO	811	650
Pb <sup>7</sup>	3.4	0.06
HAPs <sup>8</sup>	302	27.1

<sup>1</sup>Boilers are firing 100% coal. Both units can use natural gas for startup, shutdown and/or flame stabilization. The boilers can achieve nominal minimum load on these start-up/stabilization fuels but only operate in this mode for short periods of time before coal firing is established in the unit. <sup>2</sup>Actual emissions for Unit 1 and 2 consider control efficiencies of 99.9% for PM/PM<sub>10</sub> for the baghouses.

Potential to emit is based on the information identified in the table and the maimum hourly fuel consumption rate, AP-42 emissions factors and 8760 hrs/yr of operation. Potential to emit from coal handling, ash handling, haul roads and the cooling and service water towers is based on information supplied in the Title V application for regulated units. Actual emissions are based on the Division's 2000 inventory. Hazardous Air Pollutant (HAP) emissions, both potential to emit and actual, are based on the Title V permit application and APENs submitted September 30, 1996 (identifying mainly metallic HAPs), using 1995 data, as a result of the Division's request for public utilities to submit HAP addendums (APENs) on their boilers and the Division's 2000 inventory (HCl and H<sub>2</sub>SO<sub>4</sub>).

The source indicated that this facility is subject to the 112(r) Accidental Release Requirements. A risk management plan was submitted to EPA on June 3, 1999. Risk management plans were due on June 20, 1999. A revised plan was submitted on November 22, 1999 to reflect changes in the executive summary of the plan.

Both boilers are affected units and are subject to the Title IV Acid Rain provisions.

<sup>&</sup>lt;sup>3</sup>For boilers the PM PTE is based on the Reg 1 limit (0.1 lbs/mmBtu) x design heat rate x 8760 hrs/yr.

<sup>&</sup>lt;sup>4</sup> PTE for boilers is based on 92% of PM being PM<sub>10</sub>.

 $<sup>^5</sup>$ For boilers the SO $_2$  PTE is based on Reg 1 limit (1.2 lbs/mmBtu) x design heat rate x 8760 hrs/hr.  $^6$ For boilers the NO $_X$  PTE is based on the Acid Rain NO $_X$  limit x design heat rate x 8760 hrs/yr. The Acid Rain NO $_X$  limit is 0.45 lbs/mmBtu for Unit 1 and 0.50 lbs/mmBtu for Unit 2.

<sup>&</sup>lt;sup>7</sup>PTE for lead is based on uncontrolled emissions, control efficiency is 97.5%.

<sup>&</sup>lt;sup>8</sup>PTE includes <u>uncontrolled</u> emissions of metallic HAPs, control efficiencies range from 78.2 - 99.8 for these compounds.

#### III. Emission Sources

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site.

- A. Unit B001: Combustion Engineering, Model and Serial No. NB21062, Dry Bottom Tangentially Fired Boiler, Rated at 3,190 mmBtu/hr. Coal Fired with Natural Gas Used for Startup, Shutdown & Flame Stabilization.
  - 1. Applicable Requirements This unit was first placed in service in December 1973. The Title V permit application indicates that this unit is a grandfathered source from construction permits. A grandfathered source is a unit that commenced construction prior to February 1, 1972. In their December 8, 1998 additional technical information submittal, the source indicated that initial ground breaking and on-site construction for Boiler No. 1 (Unit No. 1) began on April 1, 1971. Therefore, this unit is not subject to construction permit requirements and is not subject to the requirements in 40 CFR Part 60 Subpart D (New Source Performance Standards for Fossil-Fuel-Fired Steam Generators for which Construction is commenced after August 17, 1971).

The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 3,190 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 2,534,000 lbs/hr. This maximum steam flow rating cannot be exceeded on a continuous basis.

A baghouse was installed on this unit in 1993. The baghouse replaced an electrostatic precipitator (ESP) and the installation of the baghouse was required by a January 19, 1989 Consent Order that was issued based on opacity violations that occurred during the cleaning of the ESP. This replacement of the ESP with the baghouse was not considered a modification, for purposes of PSD review, NSPS and construction permit requirements since this action did not result in an increase in emissions.

In their initial comments on the draft operating permit and technical review document, the source clarified that neither oil or natural gas can be used alone to generate power. The boiler is equipped with dual-fuel oil/natural gas ignitors which are used to heat the boiler prior to firing the unit with coal and to light the coal burners. In 1993 gas-fired burners were added for start-up purposes. The gas burners are used to bring the steam turbine on-line and to bring the baghouse up to temperature. In addition, the gas/oil ignitors and the gas burners can be used for flame stabilization when the coal is very wet or following the sudden loss of coal feed to the boiler. The Division does not consider the addition of the gas burners to be a physical change or change in the method of operation that would subject this

unit to PSD review, since this boiler was capable of accommodating natural gas prior to January 5, 1975 and was not restricted from burning natural gas in any permit issued after January 6, 1995 (see 40 CFR Part 52.21(b)(2)(iii)(e)(1) and Colorado Regulation No. 3, Part A, Section I.B.36.b(iii)(C)). This unit was originally constructed with dual-fuel oil/natural gas ignitors and a system to deliver natural gas to this unit. In their second set of comments on the draft permit received February 7, 2002, the source indicated that the gas ignitors were routinely used during start-up. Therefore, the Division considers that this unit was capable of accommodating natural gas. Although gas burners were added to the unit, EPA policy memos regarding the use of alternate fuels generally consider that the replacement or addition of burners are not considered physical or operational changes (specifically see memo from Edward Reich, dated July 28, 1983 re Bridgeport Harbor Coal Conversion and memo from James T. Wilburn, dated June 7, 1983 re Coal Conversions). Therefore, the Division does not consider the addition of the gas burners in 1993 to be a modification for purposes of PSD review, NSPS and construction permit requirements.

In their original Title V permit application, the source indicated that both natural gas and No. 2 fuel oil were used as secondary fuels. In their comments submitted on February 7, 2002 the source indicated that No. 2 fuel oil is no longer used as a secondary fuel. The original gas/oil ignitors remain, however, the fuel oil delivery system has been disconnected.

The pertinent applicable requirements for Unit 1 are as follows:

- Opacity shall not exceed 20% except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III. A.1.c)
- Continuous emission monitoring (Reg 1, Section IV)
  - o A continuous emission monitoring system for the measurement of opacity shall be installed, calibrated, maintained and operated, when burning coal (Reg 1, Section IV.B.1)
  - o Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2)
  - o If continuous emission monitor for SO<sub>2</sub>, then continuous emission monitor for either O<sub>2</sub> or CO<sub>2</sub> (Reg 1, Section IV.B.3)
  - o Calibration of continuous emission monitors (Reg 1, Section IV.F)
  - o Notification and Recordkeeping (Reg 1, Section IV.G)

- o Recordkeeping duration (Reg 1, Section IV.H)
- o Reporting requirements if fuel sampling (Reg 1, Section VI.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, on a 3-hour rolling average, when burning coal (Reg 1, Sections VI.A.1 and VI.A.3.a.(iii))
- APEN reporting (Reg 3, Part A, Section II)
- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 Fg/SCM averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement
- Acid Rain requirements as follows:
  - This unit has been allocated, on an annual basis, SO<sub>2</sub> allowances as listed in 40 CFR 73.10(b). If annual SO<sub>2</sub> emissions exceed the allocated allowances for that year, additional allowances must be obtained per 40 CFR Part 75 to cover emissions for that particular calendar year.
  - o NO<sub> $\chi$ </sub> emissions of 0.45 lbs/mmBtu on an annual average basis (source opted to comply with Phase I limits (§ 76.5(a)(1) by early election (§ 76.8)).
  - o Acid rain permitting requirements per 40 CFR Part 72.
  - o Continuous emission monitoring requirements per 40 CFR Part 75.
  - o The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emission requirements (40 CFR Part 77).

Coal is the primary fuel for this boiler. Natural gas is used as a secondary fuel during non-routine periods such as startup, shutdown and/or other flame stability efforts. The permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. The source has also indicated that this unit cannot operate on natural gas alone. Therefore, the requirements for burning solely natural gas have not been included in the operating permit. Since the requirements for burning coal are more stringent than burning natural gas alone, the source will not be required to maintain records of the heat input of natural gas and demonstrate that it comprises less than 5% of the total heat input. However, maintaining records of the consumption of natural gas will be required to determine annual emissions.

# **Streamlining of Applicable Requirements**

#### **Continuous Emission Monitors**

There are multiple requirements for Continuous Emission Monitoring (CEM)/Continuous Opacity Monitoring (COM) systems. Colorado Regulation No. 1, Section IV requires a COM (when burning coal) and either a CEM for SO<sub>2</sub> or fuel sampling. If a CEM is used for monitoring SO<sub>2</sub>, then a CEM is required for either CO<sub>2</sub> or O<sub>2</sub>. Regulation 1, Section IV identifies other requirements for CEMs such as performance specifications, calibration, and notification and recordkeeping and requirements for record retention. This unit is also subject to the Acid Rain Requirements and as such is required to continuously measure and record emissions of SO<sub>2</sub>, NO<sub>x</sub> (and diluent gas either CO<sub>2</sub> or O<sub>2</sub>), and CO<sub>2</sub> as well as volumetric flow, and opacity. The Acid Rain CEM requirements are specified in 40 CFR Part 75. The general requirement to install, calibrate, operate and maintain COMs/CEMs will be streamlined out in favor of the Acid Rain CEM requirements as they are more stringent. Streamlining of more specific CEM requirements is addressed in the paragraphs below.

The performance specification requirements for these CEMS will be subject to the Acid Rain requirements (40 CFR Part 75), since Reg 1, Section IV.E CEM performance specification requirements do not apply to this unit. The CEMs and COM will be subject to the QA/QC requirements in 40 CFR Part 75 as Reg 1 does not identify specific QA/QC requirements. In the case of the COM, the QA/QC requirements in Part 75 reference 40 CFR Part 51, Appendix M and the reference method in Appendix M that addresses the COMs (RM 203) has not been promulgated as of this date. Therefore, the calibration requirements in Reg 1, Section IV.F will be included in the permit to identify the QA/QC requirements for the COM.

The excess emissions notification and recordkeeping requirements from Regulation 1, Section IV.G have been included in the Operating Permit. Note that the record retention requirement in Regulation No. 1, Section IV.H (maintain records for 2 years) is less stringent than the Regulation No. 3, Part C recordkeeping requirement therefore, the Regulation No. 1, Section IV.H record retention requirement will be streamlined out of the permit in favor of the Regulation No. 3, Part C requirements (General Condition No. 21b & c).

#### Sulfur Dioxide (SO<sub>2</sub>)

This unit is subject to both the Regulation No. 1  $SO_2$  standards and the Acid Rain  $SO_2$  requirements. Sources subject to Acid Rain must hold adequate  $SO_2$  allowances to cover annual emissions of  $SO_2$  (1 allowance = 1 ton per year of  $SO_2$ ) for a given unit in a given year. The number of allowances can increase or

decrease for a unit depending on allowance availability. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO<sub>2</sub> requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with both the Acid Rain SO<sub>2</sub> requirements and the Reg 1 SO<sub>2</sub> standard. Note that the Acid Rain SO<sub>2</sub> allowances appear only in Section III (Acid Rain Requirements) of the permit.

**2. Emission Factors -** Emissions from boilers are generated from the combustion of fossil fuels. Type and quantities of emissions are dependent on the fuels being burned. This unit primarily burns coal, however, natural gas is used for startup, shutdown and flame stabilization. The pollutants of concern are Particulate Matter (PM and PM<sub>10</sub>), Nitrogen Oxides (NO<sub>X</sub>), Sulfur Dioxide (SO<sub>2</sub>), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated, primarily with the combustion of coal. Approval of these emission factors is necessary to the extent that accurate actual emissions are required to verify the need to submit revised APENs to update the Division's Emission Inventory.

The source proposed to use emission factors from EPA's Compilation of Emission Factors (AP-42), Section 1.1 (dated 9/98), Tables 1.1-3, 1.1-6, and 1.1-19 (subbituminous coal, pre-NSPS tangentially fired boiler) and Section 1.4 (dated 3/98), Tables 1.4-1 and 1.4-2 (natural gas, boilers > 100 mmBtu/hr, pre-NSPS).

The proposed emission factors are as follows:

Pollutant	Emission Factor Coal (lbs/ton)	Emission Factor Natural Gas (lbs/mmSCF)
PM	Source Test	1.9
PM <sub>10</sub>	0.92(PM)	1.9
SO <sub>2</sub>	CEM	CEM
NO <sub>X</sub>	CEM	CEM
CO	0.50	24
VOC	0.06	5.5

Lead emissions shall be calculated as follows:

Lead emissions (tons/yr) = Ash emitted x quantity of lead in ash

# Ash emitted (tons/yr) = $\frac{10A \text{ lbs ash/ton coal x quantity of coal burned (tons/yr)}}{2000 \text{ lbs/ton}}$

<u>where</u>: A = weight percent ash in coal (10A is the AP-42 (Section 1.1, dated 9/98) emission factor for PM)

Quantity of Lead in Ash (lbs/lbs) = content of lead in coal (ppm) x 10<sup>-4</sup> content of ash in coal (wt %)

The source will be required to use their CEMs to determine annual emissions of  $SO_2$  and  $NO_X$  for the purposes of APEN reporting and payment of fees. The emission factor for PM (when burning coal) shall be determined by annual source testing of the boiler.

This boiler is equipped with a baghouse to control particulate matter emissions. Provided the source maintains the baghouse per manufacturer's recommendations and good engineering practices, a 99.9% efficiency can be applied to the PM and PM<sub>10</sub> emission factors when burning natural gas and an efficiency of 99.3% can be included in the lead emission calculation when burning coal.

**3. Monitoring Plan -** Compliance demonstration and monitoring requirements for this unit are identified in sections 1 - 4 of Section II of the Operating Permit. Conditions 1.1 through 1.14 cover coal and Condition 2.1 addresses the firing of a natural gas as a secondary fuel.

Since the source is required to install, certify and operate continuous emission monitoring equipment for opacity,  $SO_2$ ,  $NO_X$  (including diluent gas either  $CO_2$  or  $O_2$ ),  $CO_2$  and volumetric flow, the Division will require the source to use their CEM/COM to demonstrate compliance with the opacity and  $SO_2$  requirements.

Operation of the CEM/COM in accordance with the requirements in 40 CFR Part 75 (Acid Rain Continuous Emission Monitoring Requirements) is sufficient to satisfy the requirements for operating the CEM/COM system. Part 75 defines the QA/QC requirements for the COM in § 75.21(b) and indicates that the COM shall be operated, maintained and calibrated in accordance with the procedures in 40 CFR Part 51, Appendix M. Appendix M addresses EPA reference methods and no reference methods listed appear to address opacity monitors. It appears that this reference is an error. However, the EPA has indicated that this reference is not an error, however, the reference method to address opacity monitors (reference method 203) has not been promulgated yet. Therefore, the Division is including the COM calibration requirements in Reg 1, Section IV.F in the permit for the COM QA/QC requirements. It should be noted that § 75.24(e), which addresses COM out of control periods, also references 40 CFR Part 51, Appendix M. The permit addresses alternate monitoring requirements when the COM is out of control. It should also be noted that Part 75 does not specify procedures for converting hourly SO<sub>2</sub> concentration data into units of lbs/mmBtu, except for qualifying Phase I

technologies. Reg 1, Section IV also does not specify procedures for converting  $SO_2$  concentrations to units of lbs/mmBtu. In order to convert  $SO_2$  data to units of lbs/mmBtu, to monitor compliance with the Reg 1  $SO_2$  emission limitations, the permit will specify that the conversion procedures in 40 CFR Part 60, Appendix A, Method 19 be used.

Compliance with the Acid Rain requirements are monitored by submitting quarterly data reports and annual compliance certifications to EPA electronically. With each quarterly data report, the source is required to submit a certification to EPA indicating that the monitoring data submitted was recorded in accordance with the applicable requirements. The permit requires that a copy of the annual compliance certification be sent to the Division.

Annual emission calculations, for all pollutants except  $SO_2$  and  $NO_X$ , will be required to determine compliance with APEN reporting and for determination of annual emission fees. The CEMS will be used to determine annual emissions of  $SO_2$  and  $NO_X$ . In addition, when burning coal, annual performance tests will be required to demonstrate compliance with the PM limitation. Note that depending on the results of the performance test, the frequency of stack testing for PM emissions may be decreased. The source has modeled lead emissions at "worst case" for a one-time only demonstration of compliance. The source shall be required to retain these modeling results and make them available to the Division upon request.

The source has indicated natural gas may be used in startup, shutdown and/or flame stabilization. Use of natural gas shall be recorded annually and used to calculate emissions for the purposes of APEN reporting.

- **4. Compliance Status -** The source certified in their Title V permit application that this unit was in compliance with all applicable requirements. A revised APEN was submitted with their Title V permit application. This unit is currently in compliance with all applicable requirements.
- B. Unit B002: Babcock and Wilcox, Model and Serial No. NB23761, Cross-Fired (Wall Fired) Dry Bottom Boiler, Rated at 3,122 mmBtu/hr. Coal Fired with Natural Gas Used for Startup, Shutdown & Flame Stabilization.
  - **1. Applicable Requirements -** This unit was first placed in service November 1, 1975. A construction permit (C-11,859) was issued on January 11, 1973. A final approval permit was issued April 17, 1978.

The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 3,122 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 2,534,000 lbs/hr. This maximum steam flow rating

cannot be exceeded on a continuous basis.

This unit is equipped with over-fire air to control  $NO_X$  emissions. The over-fire air was included when the unit was first built.

As discussed for Unit 1, a baghouse was installed in 1991. This baghouse replaced an ESP for the same reasons as discussed for Unit 1. In addition, as discussed for Unit 1, this action is not considered a modification for purposes of PSD review, NSPS and construction permit requirements.

As discussed for Unit 1, this unit was originally equipped with dual-fuel gas/oil iginitors and natural gas burners were added to this unit in 1991. These fuels are utilized for the same purposes as discussed for Unit 1 and as discussed for Unit 1, the Division does not consider that the addition of the natural gas burners in 1991 to be a modification for purposes of PSD review, NSPS and construction permit requirements.

As discussed for Unit 1, this unit is no longer capable of burning No. 2 fuel oil as a secondary fuel.

Permit C-11,859 contains the following applicable requirements:

- Opacity shall not exceed 20% (Condition 1)
- Particulate matter emissions shall not exceed 0.1 lbs/mmBtu (Condition 2).

In addition to the requirements in permit C-11,859, this source is subject to the following additional applicable requirements:

- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Continuous emission monitoring (Reg 1, Section IV)
  - o A continuous emission monitoring system for the measurement of opacity shall be installed, calibrated, maintained and operated, when burning coal (Reg 1, Section IV.B.1)
  - o Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2)
  - o If continuous emission monitor for SO<sub>2</sub>, then continuous emission monitor for either O<sub>2</sub> or CO<sub>2</sub> (Reg 1, Section IV.B.3)
  - o Calibration of continuous emission monitors (Reg 1, Section IV.F)
  - o Notification and Recordkeeping (Reg 1, Section IV.G)
  - o Recordkeeping duration (Reg 1, Section IV.H)
  - o Reporting requirements if fuel sampling (Reg 1, Section VI.I)

- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, on a 3-hour rolling average, when burning coal (Reg 1, Sections VI.A.1 and VI.A.3.a.(iii))
- APEN reporting (Reg 3, Part A, Section II)
- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 Fg/SCM averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement
- NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)
  - o Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu (§ 60.42(a)(1))
  - Opacity shall not exceed 20%, except for one six-minute period of not more than 27% (§ 60.42(a)(2))
  - No opacity limits during start-up, shutdown and malfunction (§ 60.11(c)).
     SO<sub>2</sub> emissions shall not exceed 1.2 lbs/mmBtu when burning coal (§ 60.43(a)(2)). SO<sub>2</sub> standard is on a 3-hr rolling average (§ 60.45(g)(i)).
  - o NO $_{\rm X}$  emissions shall not exceed 0.20 lbs/mmBtu when burning gas (§ 60.44(a)(1)) and 0.70 lbs/mmBtu when burning coal (§ 60.44(a)(3)). A prorated NO $_{\rm X}$  emission limit shall be calculated if a combination of fuels is burned (§ 60.44(b)).

The requirement to calculate a prorated NO<sub>X</sub> limit will not be included for the reasons discussed below.

Coal is the primary fuel for this boiler. Natural gas is used during non-routine periods such as startup, shutdown and/or other flame stability efforts. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion (i.e. prorating). The permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 1% of total heat input. If alternate fuel use comprises more than 5% of total heat input during a year, the permit must be reopened to include Subpart D requirements for combined fuel combustion.

- O Source shall install, calibrate, maintain and operate continuous monitoring systems for measuring opacity, SO<sub>2</sub> and NO<sub>X</sub> emissions and either O<sub>2</sub> or CO<sub>2</sub> (§§ 60.45(a), (c), (e) and (f)).
- o Excess emission reporting requirements (§ 60.45(g))
- NSPS General Provisions (40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A), specifically:

- o Good practices (§ 60.11(d))
- o Circumvention (§ 60.12)
- Acid Rain requirements as follows:
  - This unit has been allocated, on an annual basis, SO<sub>2</sub> allowances as listed in 40 CFR 73.10(b). If annual SO<sub>2</sub> emissions exceed the allocated allowances for that year, additional allowances must be obtained per 40 CFR Part 73 to cover emissions for that particular calendar year.
  - o NO<sub> $\chi$ </sub> emissions of 0.50 lbs/mmBtu on an annual average basis (source opted to comply with Phase I limits (§ 76.5(a)(2) by early election (§ 76.8)).
  - o Acid rain permitting requirements per 40 CFR Part 72.
  - o Continuous emission monitoring requirements per 40 CFR Part 75.
  - The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emission requirements (40 CFR Part 77).

# **Streamlining of Applicable Requirements**

# Continuous Emission Monitors

Streamlining of continuous emission monitoring systems requirements is the same as discussed for Unit 1, with the following exceptions. Unit 2 is required by 40 CFR Part 60 Subpart D § 60.45(a) to install calibrate, maintain and operate continuous monitoring systems for opacity, SO<sub>2</sub>, NO<sub>X</sub> and either O<sub>2</sub> or CO<sub>2</sub>. Additional monitoring requirements are identified in 40 CFR Part 60 Subpart D §§ 60.45(c), (e) and (f). As allowed by the EPA (see attached), the requirements in 40 CFR Part 60 Subparts A and D, for the continuous emission monitoring systems will be streamlined out of the permit in favor of the more stringent Part 75 requirements.

However, since as discussed for Unit 1, the COM QA/QC requirements in Part 75 have not been promulgated yet (40 CFR Part 51, Appendix M, RM 203), the COM will be subject to the NSPS QA/QC requirements. In general, the NSPS QA/QC requirements for continuous opacity monitoring systems are in 40 CFR Part 60 Subpart A § 60.13, however, some specific COM QA/QC requirements are included in 40 CFR Part 60 Subpart D § 60.45(c)(3). A review of 40 CFR Part 60.13 indicates that only 40 CFR Part 60.13(d) would apply to the COM as a QA/QC requirement. The remaining requirements in 40 CFR Part 60.13 are either applicable to the CEM or are addressed in 40 CFR Part 75.

In addition, Part 75 does not specify procedures for converting hourly SO<sub>2</sub> concentration data into units of lbs/mmBtu, except for qualifying Phase I technologies. Reg 1, Section IV also does not specify procedures for converting SO<sub>2</sub> concentrations to units of lbs/mmBtu. In order to convert SO<sub>2</sub> data to units of lbs/mmBtu, to monitor compliance with the lbs/mmBtu SO<sub>2</sub> emission limitations, the

permit will specify that the conversion procedures in 40 CFR Part 60, Appendix A, Method 19 be used. Note that since the NSPS SO<sub>2</sub> emission limitation has been streamlined out of the permit in favor of the Reg 1 SO<sub>2</sub> emission limitation (see below), the specific conversion requirements in 40 CFR Part 60 Subpart D §§ 60.45(e) and (f) will still be streamlined out of the permit, since they apply to the NSPS SO<sub>2</sub> emission limitation.

The excess emission reporting requirements in 40 CFR Part 60 Subpart D § 60.45(g) specifies that excess emission reports shall be submitted semi-annually and include the information specified in 40 CFR Part 60 Subpart A § 60.7(c). 40 CFR Part 60 Subpart A § 60.7(c) specifies that reports shall be submitted semi-annually, except when either the subpart requires more frequent reporting or the Division determines that more frequent reporting is necessary to accurately asses the compliance status of the source. The Division has determined that more frequent reporting is necessary and therefore, excess emission reports shall be submitted quarterly. Since the excess emission reports specified in Reg 1, Section IV.G and the NSPS excess emission reporting requirements both require quarterly submittals, the Reg 1, Section IV.G reporting requirements will be streamlined out of the permit in favor of the NSPS reporting requirements.

Since the NSPS QA/QC requirements (for the COM) will be included in the permit, the calibration requirements in Reg 1, Section IV.F will be streamlined out of the permit in favor of the NSPS requirements.

## Opacity

This unit is subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. This unit is also subject to the NSPS opacity requirements. The NSPS opacity requirements are not applicable during periods of startup, shutdown and malfunction in accordance with the requirement in 40 CFR Part 60 Subpart A § 60.11(c). The Reg 1 20%/30% requirements are more stringent than the NSPS opacity requirements during periods of startup, shutdown and malfunction. While the NSPS opacity requirements are more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency.

#### Sulfur Dioxide (SO<sub>2</sub>)

Streamlining of the SO<sub>2</sub> requirements is the same as discussed for Unit 1, with the

following exceptions. Unit 2 is subject to an NSPS SO<sub>2</sub> standard of 1.2 lbs/mmBtu on a 3 hour rolling average, which is the same standard as the Reg 1 SO<sub>2</sub> requirement.

Although not specifically stated in NSPS D, the Division has determined after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported with the quarterly excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards". In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, since the Regulation No. 1 SO<sub>2</sub> limit is equal to the NSPS D SO<sub>2</sub> limit and since the Reg 1 SO<sub>2</sub> limit applies all the time, the Division has streamlined out the NSPS D SO<sub>2</sub> limit in favor of the Reg 1 SO<sub>2</sub> limit. Note that although the Reg 1 SO<sub>2</sub> limit, which is included in the operating permit applies all the time, a malfunction may be reported to the Division as an upset condition in accordance with the requirements in Section II.E of the Common Provisions Regulation.

# Particulates (PM)

This unit is subject to both the Regulation No. 1 standards (included into permit C-11,859) and the NSPS standards for Particulate Matter (PM). Colorado Regulation No. 1 Section III.A.1.c (permit C-11,859) limits PM emissions to 0.1 lbs/mmBtu. The NSPS Subpart D standard is 0.1 lbs/mmBtu. As discussed under SO<sub>2</sub> above, the NSPS particulate matter standard does not apply under conditions of startup, shutdown and malfunction. The Reg 1 (permit C-11,859) standard applies all the time. Therefore, since the Regulation No. 1 particulate matter standard is equal to the NSPS D particulate matter standard and since the Reg 1 (permit C-11,859) particulate matter standard applies all the time, the Division has streamlined out the NSPS D particulate matter standard in favor of the Reg 1 (permit C-11,859) particulate matter standard. Note that although the Reg 1 particulate matter standard, which is included in the operating permit applies all the time, a malfunction may be reported to the Division as an upset condition in accordance with the requirements in Section II.E of the Common Provisions Regulation.

#### Nitrogen Oxides (NO<sub>X</sub>)

This source is subject to both the NSPS NO<sub>X</sub> requirements and the Acid Rain NO<sub>X</sub>

requirements. The Acid Rain  $NO_X$  requirement is 0.50 lbs/mmBtu based on a weighted annual average. The NSPS Subpart D standard is 0.7 lbs/mmBtu for coal based on a 3-hour rolling average. Although the Acid Rain  $NO_X$  requirements appear to be more stringent, it is possible that the source could deviate from the NSPS 3-hour average and still comply with the Acid Rain  $NO_X$  requirement since it is an annual average.  $NO_X$  data used to determine compliance with the Acid Rain requirements are submitted (electronically) to EPA for compliance demonstration. In addition, Regulation No. 3, Part C, Section V.C.1.b, requires that if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. Therefore, for these reasons the  $NO_X$  requirements have not been streamlined. The source will have to demonstrate compliance with both the Acid Rain and NSPS  $NO_X$  requirements. Note that the Acid Rain  $NO_X$  limitations only appear in Section III (Acid Rain Requirements) of the permit.

Note that as discussed for  $SO_2$  above, the NSPS  $NO_X$  standard does not apply under conditions of startup, shutdown and malfunction. Note that the NSPS still requires that those instances during periods of startup, shutdown or malfunction when the  $NO_X$  standard is exceeded be identified in the quarterly excess emission report.

- 2. Emission Factors Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit revised APENs to update the Division's Emission Inventory and for the purpose of paying fees. The same source of emission factors will be used for this unit as used for unit B001. Note that, the same tables are used to determine the emission factors, but the emission factors used are those factors specific for NSPS wall-fired boilers. The emission factors for Unit 2 are the same as those indicated for Unit 1, except that when burning natural gas, the CO emission factor is 84 lbs/mmSCF. For specific information see the discussion on Emission Factors for Unit B001.
- 3. Monitoring Plan See the discussion on the Monitoring Plan for Unit B001.

In addition to the monitoring requirements discussed for Unit B001, the source will be required to use the CEM for this unit to monitor compliance with the NSPS  $NO_X$  limitation. In addition, the COM will be required to meet the QA/QC requirements in 40 CFR Part 40 Subpart A  $\S$  60.13(d) and Subpart D  $\S$  60.45(c)(3) rather that the calibration requirements in Reg 1.

**4. Compliance Status -** The source certified in their Title V permit application that this unit was in compliance with all applicable requirements. A revised APEN was submitted with their Title V permit application. This unit is currently in compliance with all applicable requirements.

- C. Unit F001: Fugitive Particulate Emissions from Coal Handling and Storage
- D. Unit F002: Fugitive Particulate Emissions from Ash Handling, Hauling and Disposal
- E. Unit F003: Fugitive Particulate Emissions from Paved and Unpaved Roads
  - 1. Applicable Requirements The coal handling/storage and ash handling/hauling/disposal facilities were first placed into service in December 1973 and last modified in February 1976 and the paved/unpaved roads have been in operation since April 1971. In their December 8, 1998 additional technical information submittal, the source indicated that construction for the Unit 1 coal handling system commenced on April 9, 1971 and that construction for the Unit 2 coal handling system commenced on July 16, 1973. The source also indicated that the original coal handling system installed for unit 1 was designed to receive, stockpile, and reclaim coal for a two-unit plant, therefore only portions of the Unit 2 coal handling system are not grandfathered from the Reg 3, Part B construction permit requirements. Based on the information provided by the source, the Division has determined that the fugitive sources of emissions from coal handling are grandfathered from the Reg 3, Part B construction permit requirements.

The ash handling/hauling/disposal facilities are permitted under construction permit No. 87PB127F, (final approval, February 26, 1988).

All fugitive emission sources have the following applicable requirements:

Minimize fugitive particulate emissions (Reg 1, Section III.D.1.a)

Since ash handling operations are new and require a permit, the approved control plan identifies the control measures the source will take to minimize fugitive particulate emissions.

APEN reporting (Reg 3, Part A, Section II)

The 20% opacity, no off-property transport, and nuisance emission limitations identified in Regulation 1, Section III.D.1.c are guidelines not enforceable standards. However, failure to comply with the guidelines may trigger the Division to require the source to submit a fugitive dust control plan. Per Reg 1, Section III.D.1.e(i)(B) and (C), if a control plan is required, it shall be a permit violation to operate an activity for which a control plan has been disapproved or to fail to comply with the provisions of an approved control plan.

Because the ash handling was issued a permit, the ash handling has the following additional applicable requirements as identified in permit 87PB127F:

The following fugitive particulate control measures shall be applied to the

fugitive emission producing sources (condition 1):

- o haul roads shall be graveled or have a hard bottom surface
- haul roads shall be watered as necessary to remain viable as a fugitive emission control measure
- o vehicle speed shall not exceed 10 mph, this limit shall be posted
- o haul trucks shall be enclosed with fixed solid tops (not canvas or fabric)
- o water shall be applied to the clay liner during construction for compaction
- o ash disposal area shall be watered after each layer of ash is deposited and spread and in addition, as further necessary to remain viable as a fugitive emission control measure
- o topsoil stock pile revegetation shall take place as soon after stockpiling as practical
- when work in an area is completed, reclamation and revegetation of disposal modules and other non-waste areas shall be carried out as described in the Design, Construction and Operating Plan
- Fugitive particulate emissions are not to exceed the following (condition 2):

 $PM_{10}$  4.33 lbs/hr and 11.57 tons/yr

The short term emission limits were removed as a result of the Division's short term emission limit policy (based on the April 16, 1998 Colorado AQCC directive).

The annual emission limits have not been included in the operating permit for the following reasons. Fugitive emission factors typically cover a wide variety of materials and are not specific enough to provide truly accurate emissions. Fugitive emissions are not subject to annual emission fees and this source is not located in a non-attainment area. Any fugitive emission factor is based on the amount of material processed. Therefore, if the amount of material processed is limited then the emissions are limited and in this case quantifying and limiting the actual emissions with a non-specific emission factor does not provide any significant air quality benefit.

Disposal of ash shall not exceed 141,600 tons/yr (condition 3)

The construction permit was issued for the fly ash and bottom ash disposal facility. Both fly ash and bottom ash are disposed of in the same location. However, bottom ash is initially removed from the boiler and placed in ash ponds. At some point, bottom ash is removed from the ash ponds and placed in the ash disposal facility covered by construction permit 87PB127F. Since the bottom ash is wet when it is disposed of at the ash disposal facility the bottom ash is not a source of particulate matter emissions. Therefore, the limitation on ash disposed of at the disposal pit is a limit on

the fly ash disposed of and not the bottom ash. This will be clarified in the permit.

**2. Emission Factors -** Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. The presence of outdoor storage and handling of relatively fine particulate matter subjected to wind and mechanical devices results in fugitive emissions. The emissions of interest include particulate matter (PM) which is typically particulates with a relatively coarse size range and particulate matter less than 10 microns in diameter ( $PM_{10}$ ).

PM and PM<sub>10</sub> emissions are subject to APEN reporting requirements but are not subject to annual fees. New and revised APENs were submitted with the Title V permit application for these fugitive particulate emission sources. The Division will not require emission calculations for these fugitive emission sources nor specify the emission factors the source must use to calculate emissions. However, these sources are subject to the requirements of APEN reporting and the source must comply with these requirements. The emission factors included in the following section merely identify the emission factors the source has proposed to use for the types of fugitive emission sources identified in their Title V permit application.

#### 1. Coal Handling and Transportation

In their Title V permit application the source identified fugitive emission sources as emissions from coal dozers, the storage pile and unloading. After the source had submitted their Title V permit application, it was determined by the source and concurred with by the Division that they had been double counting fugitive emissions from the coal pile by performing a separate calculation for coal dozing. The emission factors the source had proposed (in their Title V permit application) to use for the storage pile, actually take into account emissions from movement and activity at the pile (i.e. coal dozing). Therefore, the source now has proposed to use the following emission factors to estimate emissions from storage and dozing at the pile.

A. <u>Emissions from coal pile maintenance and storage:</u> The source used emission factors from AP-42 (dated January 1995), Section 11.9, Table 11.9-2. The emission factors used were:

<u>Pollutant</u>	<u>Task</u>	Emission Factor <sup>1</sup>
PM PM <sub>10</sub>	Storage Pile Storage Pile <sup>2</sup>	1.6μ lbs/acre-hr 0.23(1.6μ) lbs/acre-hr
1 where:	μ = wind speed, m/sec	

 $^2$  AP-42 did not provide an emission factor for  $PM_{10}$  source assumed 23 % of PM is  $PM_{10}$ 

B. <u>Unloading of Coal:</u> In its Title V permit application, the source used emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 to estimate emissions from coal unloading. Emissions were estimated using the following equation:

$$E = \frac{k \times 0.0032 \times (U/5)^{1.3} \times D \times tons \text{ of coal transferred per year}}{(M/2)^{1.4}}$$

Where: E = particulate emissions, lbs/yr

k = particle size multiplier, dimensionless

U = mean wind speed, mph

D = number of transfer points, dimensionless

M = moisture content, %

## 2. Ash Handling and Transportation

Public Service indicated in their Title V permit application that fugitive emissions from ash handling occur when ash haul trucks are unloaded at an ash disposal site or at some other location that is not enclosed. The Title V permit application indicated that fugitive emissions from ash handling would be estimated using emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 (see equation under coal unloading above).

#### 3. Vehicle Travel on Paved and Unpaved Roads

To estimate emissions from travel on unpaved roads, the source proposed to use emission factors from AP-42 (dated January 1, 1995), Section 13.2.2 Unpaved Roads, as follows:

$$E = k \times 5.9 \times (s/12) \times (S/30) \times (W/3)^{0.7} \times (w/4)^{0.5} \times [(365-p)/365] \times VMT$$

where: E = particulate emissions, in lbs/yr

VMT = vehicle miles traveled per year

k = particle size multiplier, dimensionless

s = silt content of road surface material, in %

S = mean vehicle speed, in miles per hour

W = mean weight of vehicle, in tons

w = mean number of wheels

p = number of days with at least 0.01 in. of precipitation per year

In their Title V permit application, the source proposed to estimate emissions from vehicle travel on paved roads using emission factors from AP-42 (dated January 1995), Section 13.2.1 (paved roads). However, after the Title V permit application was submitted, the source was instructed by the Construction Permit Unit to estimate emissions from paved roads, using the emission factors in AP-42 (dated January 1995), Section 13.2.2 (unpaved roads) and a control efficiency of 85%.

**3. Monitoring Plan -**The source is subject to the APEN reporting requirements for these fugitive emission sources. The Division will not require the source to calculate emissions on any specified frequency; however, the source is responsible for submitting revised APENs as specified by Regulation No. 3, Part A, Section II.C.

These fugitive particulate emission sources are also subject to the requirements of Regulation 1, Section III.D which requires existing sources to employ control measures and operating procedures to minimize fugitive particulate emissions using all available practical methods which are technologically feasible and economically reasonable. These may include, but are not limited to watering or chemical stabilization of unpaved roads; restricting the speed of vehicles; the use of enclosures, covers, compacting and watering of storage piles and during material handling and transportation activities. The source will semi-annually certify that they have complied with the intent of this regulation.

Since the ash handling and disposal operations were issued a permit with a fugitive dust control plan, the requirements in the fugitive dust control plan shall be included in the permit. In addition, since there is a limitation on the quantity of ash disposed or, the source shall be required to record the quantity of ash disposed and maintain a 12 month rolling total of ash disposed to monitor compliance with the limitation.

The quantity of fly ash shall be determined based on the quantity of coal consumed, the average ash content of the coal, an 80% fly ash factor and facility records, as necessary.

**4. Compliance Status -** The source certified in its Title V permit application that they were in compliance with all applicable requirements for fugitive emissions from coal handling and ash handling. The source indicated in its Title V permit application that they were out of compliance with the APEN reporting requirements for fugitive emissions from vehicle travel on paved and unpaved roads. An APEN was submitted with the Title V permit application and therefore, the source is currently in compliance with all applicable requirements.

#### F. Units P001 & P002: Ash Silos

1. Applicable Requirements - In its Title V permit application, the source had grouped all of its particulate emission sources from ash handling together and identified all sources as fugitive sources. However, not all emissions from ash handling are fugitive. The loading and unloading of the ash silos is considered a point source and as such is subject to emission fees. The ash silo for Boiler No. 1 is grandfathered (construction commenced/in operation prior to February 1, 1972) from the construction permit requirements in Colorado Regulation No. 3, Part B.

Construction of the ash silo for Boiler No. 2 commenced in 1973 and operation began in late 1975 and therefore this silo is not grandfathered from the construction permit requirements in Reg 3, Part B. The Division had previously determined that the source was using inappropriate emission factors for the ash silo and with the Division specified emission factors, emissions for ash silo No. 2 exceed APEN de minimis levels and therefore a construction permit is required for this unit. No construction permit was previously issued for this unit, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that this unit can comply with the applicable requirements. The silo for Boiler No. 1 (P001) has the following applicable requirements:

• 20% opacity (Regulation No. 1, Section II.A.1)

Based on engineering judgement, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin loading or unloading); 2) process modifications are

unlikely since the process of loading and unloading is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or unloading) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

APEN reporting (Reg 3, Part A, Section II)

The silo for Boiler No. 2 (P002) has the following additional applicable requirements:

- PM emissions not to exceed 0.97 tpy (based on information provided by the source in a memo dated August 4, 1998))
- PM<sub>10</sub> emissions not to exceed 0.97 tpy (based on information provided by the source in a memo dated August 4, 1998))
- Fly ash handling not to exceed 62,841 tpy (based on information provided by the source in a memo dated August 4, 1998))
- Efficiency of the baghouse is 99.9%. When loading dry ash to an enclosed truck, the combination of the boiler baghouse and the hose connection has an efficiency of 95%.

Note that no efficiency requirements will be put in the Operating Permit as it is difficult to measure efficiency. In lieu of including control efficiencies in the permit, the source will be required to follow operation and maintenance guidelines to assure that control equipment is functioning properly.

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Operations (loading and unloading) at the ash silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). The Division also does not consider the ash silo to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the ash is a by-product of operating the boiler and no "product" is made with the ash, nor is it processed further. The purpose of the silo is to store ash until it is removed for sale or disposal.

**2. Emission Factors -** The source has identified two (2) sources of emissions from the ash silo.

The first source is loading ash from the boiler baghouse to the silo. This is performed by a blower system that pneumatically conveys the ash from the baghouse hoppers to the top of the ash silo. At this point, ash falls into the silo while the conveying air is drawn out of the silo by a bin vent fan which keeps the silo under constant negative pressure of -1 to -3 inches of water. The exhaust from the silo bin vent fan is connected to the boiler baghouse inlet duct. Therefore, air from the ash silo ultimately vents through the boiler baghouse for particulate control and out the boiler stack.

The second source of emissions is from unloading ash into an enclosed truck or rail car. Dry ash is loaded into enclosed trucks or rail car. For this process a long hose is connected to the enclosed truck or rail car. This hose is equipped with an outer exhaust pipe that collects dust from around the inner hose and also pulls air out of the enclosed truck or rail car. Air from this exhaust is ducted to the ash silo and eventually passes through the boiler baghouse.

Approval of emission factors is necessary to the extent that emission factors shall be used to demonstrate compliance with the annual emission limits. The source proposed using the following emission factors to calculate emissions for the purposes of demonstrating compliance with the emission limits. Emission factors are from EPA's Compilation of Emission Factors (AP-42), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck, dated January 1995. The emission factors are as follows:

<u>Pollutant</u>	EF (lbs/ton)	Source	<b>Assumed Efficiency</b>
PM	0.61	loading <sup>1</sup>	Baghouse - 99.9%
$PM_{10}$	0.61	loading <sup>1</sup>	Baghouse - 99.9%
PM	0.61	unloading1	Combination <sup>2</sup> - 95%
$PM_{10}$	0.61	unloading 1	Combination <sup>2</sup> - 95%

<sup>&</sup>lt;sup>1</sup>Specifically from Table 11.17-4, Product Unloading - Enclosed Truck <sup>2</sup>Combination of boiler baghouse and hose connection

- 3. Monitoring Plan For silo No. 1, the source shall be required to record ash throughput and calculate emissions annually for the purposes of APEN reporting. For silo No. 2, the source shall be required to record ash throughput and calculate emissions monthly. Ash throughput shall be based on the quantity of coal consumed, the average ash content of the coal and a presumed 80/20 fly ash/bottom ash split. In the absence of credible evidence to the contrary, opacity emissions from the ash silo and unloading operations shall be presumed to be in compliance with the opacity requirements provided the control devices are properly maintained and operated.
- **4. Compliance Status -** Ash silo No. 1 is in compliance with all applicable requirements. When the Title V permit application was submitted Ash silo No. 2 was not permitted. Emissions from both ash silos had been included in the APEN submitted with the Title V permit application for ash handling. Upon determination that ash silo No. 2 was subject to permitting requirements, the source requested a permit. No construction permit was issued, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-

certification that this unit can comply with its applicable requirements.

- G. Unit P003: Unit No. 1 Coal Handling System (Conveying and Crushing)
   H. Unit P004: Unit No. 2 Coal Handling System (Conveying and Crushing)
  - 1. Applicable Requirements In its Title V permit application, the source had grouped all of its particulate emission sources from coal handling together and identified all sources as fugitive sources. However, some of the sources identified in the permit application as fugitive could be reasonably controlled and therefore are considered non-fugitive emission sources. Those activities not associated with the outdoor storage pile (i.e. wind erosion and coal dozing) have been considered non-fugitive sources.

The source indicated in its title V permit application that coal handling/storage facilities were first placed into service in December 1973 and last modified in February 1976. In their December 8, 1998 additional technical information submittal, the source indicated that the coal handling system was modified to install coal handling equipment for Unit No. 2. Construction for the Unit No. 2 coal handling system commenced in July 1973 and Unit No. 2 began operation in February 1976. Therefore, portions of the Unit No. 2 coal handling system (No. 2 coal silos, tripper conveyor No. 11, transfer conveyor No. 10, transfer tower No. 5, plant conveyor No. 8, crusher No. 2, reclaim conveyor No. 6, and reclaim feeders No. 3 and 4) should have been permitted as required by Colorado Regulation No. 3, Part B. The Division did not issue a construction permit for the Unit 2 coal handling system, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that this unit can comply with the applicable requirements.

A site visit of the facility was conducted to review the coal handling system. During this visit, the source indicated that modifications had been made in 1995 to both the Unit No. 1 and Unit No. 2 coal handling systems. These modifications consisted of additional controls to reduce dust in the system. Typically the modifications were the addition of baffles or enclosures to reduce dust at certain points in the system or the addition of spray bars to suppress dust. The 1995 modifications are distinguished from the rest of the coal handling system as these portions are painted purple. Since these modifications reduce dust they are not considered modifications for the purposes of Reg 3, Part B (construction permits).

The Unit 1 coal handling system has the following applicable requirements:

20% opacity (Regulation No. 1, Section II.A.1)

Based on engineering judgement, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin conveying and/or crushing); 2) process modifications are unlikely since the process of conveying or crushing is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. conveying and/or crushing) and 3) the control equipment cannot be adjusted while conveying or crushing is occurring.

APEN reporting (Reg 3, Part A, Section II)

The Unit 2 coal handling system has the following additional applicable requirements:

- PM emissions not to exceed 9 tons/yr (as identified in Title V permit application submitted 2/15/96)
- PM<sub>10</sub> emissions not to exceed 4 tons/yr (as identified in Title V permit application submitted 2/15/96)
- Quantity of coal handled shall not exceed 1,603,800 tons/yr (identified in Title V permit application submitted 2/15/96 as the maximum annual coal consumption for Unit No. 2)

The Division determined that no Regulation No. 1 particulate matter standards were applicable. These operations (crushing and conveying) are not considered fugitive emissions (PM requirements - Reg 1, Section III.D) since these sources can be reasonably controlled. The Division also does not consider coal conveying and crushing to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the coal is not used in manufacturing but is used in fuel burning equipment which has PM requirements in Reg 1, Section III.A.

- 2. Emission Factors The source indicated that the non-fugitive emission sources from coal handling were conveying of coal and crushing of coal. The Division agrees with this interpretation. Approval of emission factors is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division's inventory. The source identified the following emission factors:
- A. <u>Coal Conveying:</u> There are no specific emission factors for conveying coal. Therefore, the source proposed to estimate emissions from coal conveying as emissions from each of the drop or transfer points in conveying the coal from the storage pile to the boilers. The Division believes that this is a reasonable method to estimate emissions from coal conveying. The source proposed to use emission

factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4. Emissions from each transfer point (dropping material on a received surface) can be estimated using the following equation:

$$E = k \times 0.0032 \times (U/5)^{1.3} \times D \times tons of coal transferred per year (M/2)^{1.4}$$

Where: E = particulate emissions, lbs/yr

k = particle size multiplier, dimensionless

U = mean wind speed, mph

D = number of transfer points, dimensionless

M = moisture content, %

Note that permitted emissions are based on six (6) transfer points, a wind speed of 8.6 mph (per Title V permit application submitted 2/15/96), a moisture content of 4.5% (based on AP-42, Section 13.2.4, Table 13.2.4-1) and a maximum coal consumption of 1,603,800 tons/yr.

B. <u>Coal Crushing:</u> The source proposed to use emission factors from EPA's FIRE Version 5.0, Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants (EPA-454/R-95-012), dated August 1995 (SCC 3-05-010-10). The emission factors are:

<u>Pollutant</u>	Emission Factor
PM	0.02 lbs/ton coal
$PM_{10}$	0.006 lbs/ton coal

Note that permitted emissions are based on a maximum coal consumption rate of 1,603,800 tons/yr for Unit No. 2 and a 90% efficiency for the enclosure on the crusher for Unit No. 2. The 90% efficiency can be used in calculating emissions provided the integrity of the No. 2 crusher enclosure is maintained.

3. Monitoring Plan - Monitoring requirements shall include maintaining annual records of coal throughput and calculating emissions annually for the Unit No. 1 coal handling system. The source will be required to record coal throughput monthly for the Unit No. 2 coal handling system. In the absence of credible evidence to the contrary, compliance with the Unit 2 emission limitations is presumed, provided the coal throughput is within the limitations and the moisture content of the coal is no less than 4.5%. In the absence of credible evidence to the contrary, compliance with the opacity requirements shall be presumed provided the baghouse (for Unit No. 1 coal bunkers and the transfer tower for both Units No. 1 and 2) and particulate matter control system (Unit No. 2 coal bunkers) are properly maintained and operated, the water spray systems (conveyors) are operated as needed and the integrity of the enclosures are maintained (conveyors and crushers).

- **4. Compliance Status -** The Unit No. 1 coal handling system is in compliance with all applicable requirements. The Unit No. 2 coal handling system was previously not permitted. An APEN was submitted with the Title V permit application reporting emissions of fugitive particulate emissions from coal handling operations from both Units No. 1 and 2. Both fugitive and non-fugitive sources were included in this APEN. Upon determination that the No. 2 coal handling system was subject to permitting requirements, the source requested a permit. No construction permit was issued, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that this unit can comply with its applicable requirements.
- H. Unit M001: Unit 1 Cooling Water and Service Water Towers
- I. Unit M002: Unit 2 Cooling Water and Service Water Towers
  - 1. Applicable Requirements There is a cooling water tower (rated at 140,000 gal/min) and a service water tower (rated at 17,000 gal/min) for each boiler. The Unit 1 cooling water and service water towers were first placed in service in December 1973. The Unit 2 cooling water tower and service water tower were first placed in service in November 1975. As discussed for Boiler No. 1, construction commenced on the cooling water and service water tower prior to February 1, 1972.

In their Title V permit application, the source indicated that these units were modified in 1994-1995. In their comments on the draft operating permit and technical review document, the source indicated that maintenance and repair activities have been conducted on the cooling and service water towers beginning in 1994-1995 and continuing through 2001. The cooling tower maintenance work included like-kind replacement of structural members, fill material and fan decks as needed. The wooden cooling water distribution headers were also replaced with fiberglass piping due to deterioration. Also the drift eliminators were replaced with newer, more efficient models to reduce drift loss from the drift eliminators. There were no changes or upgrades made to the cooling water pumps as part of the maintenance project, therefore, no increase in emissions would have resulted from these changes.

The only subproject in the cooling/service water tower maintenance project that was not an in-place, like-kind repair and replacement was the relocation and reconstruction of the Unit 1 service water tower. The original location of this unit, between boilers 1 and 2 restricted airflow to the tower which affected its cooling ability and interfered with the location of a new induced draft fan and associated

ductwork necessary for the new baghouse installation. The tower was demolished in its original location and rebuilt in a new location. During the rebuild of the tower, one additional cell was added but no changes to the cooling water source or circulating pumps design flow were made. Therefore, the rebuild resulted in no increase in emissions. The Division considers that the changes made to the cooling towers are not considered modifications for purposes of permitting requirements.

When the Title V permit application was initially submitted an APEN was submitted for the cooling/service water towers. Based on the information in the Title V permit application, regarding changes made to the cooling/service water towers made in 1994-1995, the Division issued a construction permit (Colorado Construction Permit 96PB153-2, initial approval, dated June 11, 1998) for these units. The source indicated in their comments on the draft operating permit that since the cooling and service water towers for Unit 1 were not modified (i.e. no changes made that resulted in an increase in emissions) and since construction on these units commenced prior to February 1, 1972 that these units are not subject to construction permit requirements. The Division agrees and construction permit 96PB153-2 will be revised to address only the cooling and service water towers for Unit 2.

The Unit 2 cooling and service water towers were moved to final approval status based on the self-certification by the source submitted to the Division on September 2, 1998 stating that these units were fully in compliance with the applicable requirement listed in construction permit 96PB153-2.

The Unit 1 cooling and service water towers are subject to the following applicable requirements:

20% opacity (Regulation No. 1, Section II.A.1)

Based on engineering judgement, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no "startup" involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the 30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with these units.

APEN reporting (Reg 3, Part A, Section II)

The Unit 2 cooling and service water towers are subject to following applicable

requirements as identified in construction permit 96PB153-2:

• Emissions of air pollutants shall not exceed the following limitations (condition 2):

PM 4.31 tons/yr PM<sub>10</sub> 4.31 tons/yr VOC 4.35 tons/yr

Note that the above emission limits include emissions from the Unit 1 cooling and service water tower, which are not subject to construction permit requirements. Therefore, as indicated in their comments on the draft operating permit, the emission limits will be changed to reflect only emissions from the Unit 2 cooling and service water towers. The PM and  $PM_{10}$  emission limits will be 2.16 tons/yr and the VOC emission limit will be 2.18 tons/yr.

- The source shall be limited to the following operating parameters (condition 3):
  - o water flow shall not exceed 1605.03 x 10<sup>9</sup> gal/yr
  - o total dissolved solids/total suspended solids concentration shall not exceed 2,000 ppm
  - o chlorination shall not exceed 974 hrs per year

Again, as noted under the emission limits above, the water flow limits include water flow limitations for the Unit 1 cooling and service water towers, which are not subject to construction permit requirements. Therefore, as indicated in their comments on the draft operating permit, the water flow limits will be changed to 82,519 mmgal/yr in order to reflect only the Unit 2 cooling and service water towers.

The source indicated, in comments on another facility's permit, that the intent of the total solids limit in construction permits was to provide design levels to set an emission limit and to set maximum parameters that determine emissions. The intent was for the source to demonstrate that they were below maximum parameters and therefore demonstrate compliance with emission limits, without performing calculations. However, since the operating permit requires monthly emission calculations, there is no need to set a limit on the total solids concentration. Therefore, the total solids concentration limit has not been included in the operating permit.

Since the chlorination rate is used to determine emissions of chlorine (a HAP) from the Unit 2 cooling and service water towers it will not be included in the permit as a limitation since the Division does not have the authority to limit HAP emissions unless a source is requesting a synthetic minor limitation. In addition, although the source is required to report emissions of

HAPs for the purposes of APEN reporting and payment of fees, the Division's policy is not to include these calculations in the specific portions of the operating permit. The APEN reporting requirements and the requirement to pay annual fees are included in the General Conditions of the operating permit and the source is still subject to these requirements. It should be noted that in comments on the draft permit received on February 7, 2002, the source indicated that have reviewed the chlorine emission calculations that were originally used to determine chlorine emissions in the original Title V application and the cooling tower APENS submitted with this application. The reason for reviewing the calculations is that several of the source's facilities switched from chorine gas to liquid sodium hypochlorite. With this review, the source believes that neither chlorine gas or the liquid sodium hypochlorite solutions result in chlorine emissions from the cooling towers.

Although not specifically identified in the construction permit, the Unit 2 cooling water/service water towers are also subject to the 20% opacity requirement in Colorado Regulation No. 1, Section II.A.1, as indicated above for the Unit 1 cooling/service water towers. In their Title V permit application, the source indicated that in a meeting with the Division (September 6, 1995 pre-application meeting), both the Division and Public Service agreed that cooling towers are always in compliance with the 20% opacity requirement. The Division does believe that it would be highly unlikely that a cooling tower would ever violate the 20% opacity requirement. The Division considers that although it is unlikely that the cooling/service water towers would violate the 20% opacity requirement, this requirement must be included in the operating permit. Therefore, the Division considers that the cooling/service water towers are, in the absence of credible evidence to the contrary, in compliance with the opacity requirements provided the cooling/service water towers and their associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

In addition, as discussed for the Unit 1 cooling and service water towers, the Division believes that for purposes of opacity emissions none of the conditions under Req 1, Section II.A.4 apply.

2. Emission Factors - Since cooling water/service water towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as "drift" droplets. Particulate matter contained in the "drift" is considered an emission as well as any chlorine or chloroform from water treatment chemicals used in the cooling/service water tower. Approval of emission factors for these units are necessary to verify compliance with the emission limits. The source proposed to calculate emissions from the cooling water/service water towers in the following manner:

PM = PM<sub>10</sub> = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (31.3% PM/PM<sub>10</sub> from drift) x

(total solids concentration, ppm)

Where: % drift = 0.001%

31.3% PM from drift - from EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift -

Volume 1, Technical Report", page 63

 $VOC = CHCl_3 = (water flow, gpm) x (0.0527 lbs CHCl_3/mmgal)$ 

Where: 0.0527 lbs/mmgal emission factor - from letter from Wayne C. Micheletti to

Ed Lasnic, dated November 11, 1992 (see attached)

3. Monitoring Plan - For the Unit 1 cooling/service water towers, the source will be required to monitor and record the water circulation rate and calculate emissions annually. In order to calculate emissions, the total solids content of the circulating water in each tower shall be analyzed annually. For the Unit 2 cooling/service water towers, the source will be required to monitor and record the water circulation rate and calculate emissions monthly. Since the total solids concentration for the Unit 2 cooling/service towers has remained fairly consistent and below 2,000 ppm (the level at which the emission limits were set), the permit will require that the total solids content of the circulating water in each tower be analyzed semi-annually.

**4. Compliance Status -** The source indicated in their Title V permit application that the cooling water/service water towers were out of compliance with the APEN reporting requirements. An APEN was submitted with the Title V permit application and construction permit 96PB153-2 was subsequently issued.

# IV. Insignificant Activities

General categories of insignificant activities include: in-house experimental or analytical laboratory equipment, fuel (gaseous) burning equipment < 5 mmBtu/hr or < 10 mmBtu/hr (for heating), chemical storage tanks/containers < 500 gal or storage areas < 5,000 gal, landscaping and site housekeeping equipment (< 10 hp), storage of butane, propane or NGL (vessels < 60,000 gal) and venting of cylinders (< 1 gal), lube oil storage tanks (< 40,000 gal) and other storage tanks (limited throughput and contents), fuel storage and dispensing equipment, stationary internal combustion engines (limited size and hours of operation) and sources with emissions less than APEN de minimis. Specific insignificant activities identified in the Title V permit application are:

<u>Units with emissions less than APEN de minimis - criteria pollutants (Reg 3 Part C.II.E.3.a)</u>

Solvent Cold Cleaners (VOC emissions < 2 tpy)
Venting of Natural Gas and Leaks (VOC emissions < 2 tpy)
Sulfuric Acid Tank, 15,000 gal aboveground (emissions < 2 tpy)

Boiler Steam Vents - emit VOC from injection of VOCs as treatment chemicals (< 2 tpy of VOC used)

Air conditioning or ventilation systems not designed to remove air pollutants (Reg 3 Part C.II.E.3.c)

Plant Air Conditioning and Ventilation System

In-house experimental and analytical laboratory equipment (Reg 3 Part C.II.E.3.i)

Plant Laboratory

Fuel (gaseous) burning equipment < 5 mmBtu/hr (Reg 3 Part C.II.E.3.k)

Propane Portable Heaters
Administration Building Heater
Hot Water Heater
Two (2) Southern Substation Building Heaters

Welding, soldering and brazing operations using no lead-based compounds (Reg 3 Part C.II.E.3.r)

Maintenance Welding Machine

Chemical storage tanks or containers < 500 gal (Reg 3 Part C.II.E.3.n)

Small Chemical Storage Tanks

Battery recharging areas (Reg 3 Part C.II.E.3.t)

Battery Storage Area

Landscaping and site housekeeping devices < 10 hp (Reg 3 Part C.II.E.3.bb)

Mowers, Snowblowers, Etc.

Fugitive emissions from landscaping activities (Reg 3 Part C.II.E.3.cc)

Emergency events such as accidental fires (Reg 3 Part C.II.E.3.ff)

Operations involving acetylene, butane, propane or other flame cutting torches (Reg 3 Part C.II.E.3.kk)

Portable Welding Torches

Chemical storage areas < 5,000 gal capacity (Reg 3 Part C.II.E.3.mm)

Oil Drum Storage Area

Emissions of air pollutants which are not criteria or non-criteria reportable pollutants (Reg 3 Part C.II.E.3.00)

Liquid Alum Tank, 12,500 gal aboveground Wastewater Operations (no VOC emissions)

Janitorial activities and products (Reg 3 Part C.II.E.3.pp)

Office emissions including cleaning, copying, and restrooms (Reg 3 Part C.II.E.3.tt)

Fuel storage and dispensing equipment in ozone attainment areas throughput < 400 gal/day averaged over 30 days (Reg 3 Part C.II.E.3.ccc)

Diesel Fuel Tank (1,034 gal) for Refueling Heavy Coal Handling Equipment Diesel Fuel Tank (300 gal) for Plant Vehicles Unleaded Gasoline Tank (300 gal) for Plant Vehicles

Storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications (Reg 3 Part C.II.E.3.fff)

Diesel Fuel Tank (1,000 gal) for Emergency Generator Diesel Fuel Tank (363 gal) for Emergency Fire Water Pump North Fuel Oil Tank (325,000 gal aboveground) South Fuel Oil Tank (325,000 gal aboveground)

Stationary Internal Combustion Engines - limited hours or size (Reg 3 Part C.II.E.3.nnn(ii))

Emergency Diesel Generator (630 hp and runs < 250 hrs/yr)

Sandblast equipment where blast media is recycled and blasted material is collected (Reg 3 Part C.II.E.3.www)

Sandblasting Machine

Nonroad Engines - limited hours or size (Reg 3 Part C.II.E.3.xxx(1)(vi)

Emergency Diesel Fire Water Pump (280 hp and runs < 850 hrs/yr)

<u>Chemical storage tanks - sodium hydroxide storage tanks (Reg 3 Part C.II.E.3.eeee.(ii))</u>

Caustic Tank, 15,000 gal aboveground

#### Not sources of emissions

Turbine 1, lube oil system (closed system)
Turbine 1, lube oil system (closed system)

The source also identified mobile engine tailpipe emissions as an insignificant activity. Emissions from these sources would not necessarily qualify them as an insignificant activity but they are not applicable to Title V permitting requirements since they are mobile sources. Therefore, emissions from mobile sources are not identified in the draft permit as an insignificant activity.

# V. Alternative Operating Scenarios

#### A. Alternate Fuels

The primary fuel used for both boilers is coal. Natural gas is used during non-routine periods such as startup, shutdown and/or other flame stability efforts.

# **B.** Chemical Cleaning of Boilers

The source has also requested, in a November 15, 1996 submittal (see attached), that boiler chemical cleaning be allowed as an insignificant activity. The Division has previously indicated that this activity does not require permitting. After a boiler has been cleaned the waste cleaning solutions are evaporated in a boiler. In order to be consistent with other power plant Operating Permits and because the Division is placing some requirements on the cleaning events, the chemical cleaning of boilers is being included in the Operating Permit as an alternative operating scenario. A permit (88DE245, initial approval, September 27, 1988) for the temporary evaporation of boiler cleaning solutions was issued for a boiler at Arapahoe Station (see attached). The Division later indicated that no permit was required for this activity and that the source should request that the permit be canceled. Although the permit has been canceled and is no longer valid, it was used as a guide to identify reporting and operating requirements for the alternative operating scenario of evaporating chemical cleaning solutions in the boilers. The only requirement from Permit 88DE245 that was included in the Operating Permit was that any air pollution control equipment shall be operated during evaporation of the cleaning solutions. Permit 88DE245 required that prior notification of the cleaning event, including the amounts and types of cleaning solutions to be evaporated as well as the evaporation rate be provided to the Division. In order to be consistent with the requirement for alternative operating scenarios (Reg 3, Part A, Section IV.A), the Division is requiring that the source maintain records of the

date and time the cleaning event starts and ends and the amounts and types of chemicals used in the event. Permit 88DE245 also indicated that the source was subject to the requirements of Regulation No. 8, Sections IV and VI, which limit ambient impacts of mercury and lead. The Division has already included requirements in the Operating Permit for demonstrating compliance with the lead emission requirements in Regulation No. 8, Section IV and therefore does not believe that any further demonstration is required when cleaning the boiler. The Division no longer has a state standard for mercury and the NESHAP for mercury (40 CFR Part 61, Subpart D) is not applicable to mercury emissions that may occur from coal-fired utility boilers.

#### VI. Permit Shield

The source identified and justified a short list of non-applicable requirements that they wish to be specifically shielded from. The non-applicable requirements that the source will be shielded from are as follows:

A. 40 CFR Part 60, Subparts D, Da, Db and Dc (as adopted by reference in Colorado Regulation No. 6, Part A), Standards of Performance for Steam Generators - The permit application states that these requirements are not applicable as both boilers commenced construction before August 7, 1977. This justification is not completely correct. The shield is being granted for Boiler No. 1 for the following reasons: construction commenced prior to August 17, 1971 (D, Da and Db) and the boilers are not small industrial-commercial-institutional steam generating units (Dc). For Boiler No. 2, the shield cannot be granted for NSPS D, since this unit did not commence construction prior to August 17, 1971. However, the shield for NSPS Da and Db will be granted since construction commenced prior to September 18, 1978 and the shield for NSPS Dc will be granted since this unit is not a small industrial-commercial-institutional steam generating unit.

Note that although the electrostatic precipitators (ESPs) for these units were replaced with baghouses in 1993 (units 1) and 1991 (unit 2), these replacements were not considered modifications, because the NSPS regulations (40 CFR Part 60 Subpart A § 60.14(e)(5)) exempts the addition of control equipment from the definition of a modification, except when an emission control system is removed or is replaced by a system that is determined to be less environmentally beneficial. A baghouse is more efficient at removing particulate matter than the ESP, therefore the replacement of the ESPs with baghouses is not considered a modification for purposes of NSPS.

It should also be noted that although gas burners were added to these units in 1993 (unit 1) and 1991 (unit 2) that this addition is not considered a modification, because the NSPS regulations (40 CFR Part 60 Subpart A § 60.14(E)(4)) exempts the use of alternate fuels from the definition of a modification when the existing facility was designed to accommodate that use. As indicted under the discussions

for each boiler, the boilers were initially constructed with dual-fuel gas/oil ignitors, therefore, these boilers could always accommodated natural gas as fuel.

B. 40 CFR Part 60, Subpart Y (as adopted by reference in Colorado Regulation No. 6, Part A), Standards of Performance for Coal Preparation Plants - The permit application states that these requirements do not apply because this NSPS applies only to coal preparation plants and that while this facility does prepare coal for its own use it is not a coal preparation plant as defined in 40 CFR Part 60, Subpart Y (i.e. it does not sell prepared coal to users). This justification is incorrect as the definition of a coal preparation plant in 40 CFR Part 60 Subpart Y § 60.251(a) does not distinguish between facilities preparing coal for their own use and facilities preparing coal for sale to other users, nor does the applicability requirements (§ 60.250) specifically state that the requirements apply only to plants that sell prepared coal to other users. However, the Division has concluded that these requirements are not applicable because the coal handling systems at this facility commenced construction prior to October 24, 1974. The shield is being granted for this justification.

Note that although changes were made to the control handling system in 1995 these changes were not considered modifications, because the NSPS regulations (40 CFR Part 60 Subpart A § 60.14(e)(5)) exempts the addition of control equipment from the definition of a modification. The changes made to the coal handling system were to reduce dust.

C. Colorado Regulation No. 6, Part B, Section II, Standards of Performance for New Fuel Burning Equipment - The source did not request the shield for this requirement; however, the Division included this to be consistent with other shield requests made in the Title V application for this facility. This requirement is not applicable because the boilers commenced construction prior to January 30, 1979 and the shield was granted for this reason.

Note that Colorado Regulation No. 6, Part B adopts the NSPS general provisions by reference (40 CFR Part 60 Subpart A) and for the same reasons as discussed under Item A above (shield for NSPS Subparts D, Da, Db and Dc), the changes made to the boilers (replace ESP with baghouse and addition of natural gas burners) are not considered modifications for the purposes of these requirements.

D. 40 CFR Part 63, Subpart Q (as adopted by reference in Colorado Regulation No. 8, Part E) - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers - The permit application states that this requirement is not applicable because the cooling towers do not use chromiumbased water treatment chemicals. The shield was granted based on the source's justification.

- E. Colorado Regulation No. 7 (except for Section V, Paragraphs VI.B.1 and 2, and Subsection VII.C), Volatile Organic Compounds The permit application states that these regulations are not applicable because the source is not located in an ozone non-attainment area. Regulation No. 7 only applies to sources located in ozone non-attainment areas or in the Denver Metro Attainment Maintenance Area with the exception of Section V, Paragraphs VI.B.1 and 2, and Subsection VII.C which are applicable statewide. The permit shield was granted based on the source's justification.
- F. Colorado Regulation No. 7, Section V.B This requirement is not applicable as the facility is not a bulk gasoline terminal, bulk gasoline plant or gas dispensing facility.
- G. Colorado Regulation No. 7, Sections VI.B.1 and 2 These requirements are not applicable as the liquids stored in tanks greater than 40,000 gallons are exempt from the provisions of Section VI.B.2, per Section VI.B.1.a.
- H. Colorado Regulation No. 7, Section VII.C This requirement is not applicable as crude oil is not stored in tanks exceeding 40,000 gallons.

The source requested the permit shield from the Prevention of Significant Deterioration requirements in 40 CFR 52.21 (Colorado Regulation 3, Part B, Section IV.D.3). The source's justification in the permit application states that this requirement is not applicable as the boilers were constructed before and has had no major modifications after August 1, 1977. In comments received on another operating permit, EPA indicated that the Division could not grant the shield for PSD review requirements, unless the source was an existing source prior to August 7, 1977. Although this facility was an existing stationary source prior to August 7, 1977, equipment has been added to the facility after August 7, 1977 and therefore the Division cannot grant the permit shield for the PSD review requirements.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

#### Boiler No. 1, Unit B001

 Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section IV.A, B & H), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirements for retaining records in Reg 3, Part C (general condition 21 in the operating permit) is more stringent.

Boiler No. 2, Unit B002

- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section IV.A, B, F, G and H), streamlined out since the NSPS COM/CEM requirements are more stringent. In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since the Acid Rain CEM QA/QC requirements are more stringent and the NSPS QA/QC requirements for COMS (40 CFR Parts 60.13 and 60.45(c)(3)) are more stringent. In the case of Reg 1, Section IV.G, the reporting requirements were streamlined out in favor of the NSPS excess emission reporting requirements. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirements for retaining records in Reg 3, Part C (general condition 21 in the operating permit) is more stringent.
- 0.1 lbs/mmBtu particulate matter emission limit (40 CFR Part 60 Subpart D § 60.42(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the Reg 1, Section III.A.1.c is more stringent as this standard applies at all times.
- 1.2 lbs/mmBtu SO<sub>2</sub> emission limit (40 CFR Part 60 Subpart D § 60.43(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since the Reg 1, Section VI.A.3.a(ii) is more stringent as this standard applies at all times.
- Continuous Emission Monitoring Requirements (40 CFR Part 60 Subpart D §§ 60.45(a), (c), (e) & (f) install CEMs/COM, performance evaluation & calibration checks and data conversion procedures), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent, except that the QA/QC requirements as they apply to COMs in 60.45(c)(3) will remain in the permit.

#### VII. Acid Rain Provisions

This source is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. This facility has been allocated, on an annual basis,  $SO_2$  allowances (1 ton per year of  $SO_2$ ) as listed in 40 CFR 73.10(b)(2). The source opted to comply with the Phase I  $NO_X$  which are 0.45 lbs/mmBtu, on an annual average basis, for Unit 1 and 0.5 lbs/mmBtu, on an annual average basis, for Unit 2.

As an affected unit under the Acid Rain Program, Units 1 and 2 must continuously measure and record emissions of  $SO_2$ ,  $NO_X$  (including diluent gas either  $CO_2$  and  $O_2$ ), and  $CO_2$ , as well as volumetric flow and opacity. The source submitted the continuous emission monitoring (CEM) certification package on January 1, 1995.

# VIII. Accidental Release Program - 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provision must develop and

implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare ar implement a Risk Management Plan (RMP) as specified in the Rule.  This facility is subject to the provisions of the Accidental Release Prevention Program and has submitted a RMP to the U.S. EPA.	nd